

**THE OFFICE OF REGULATORY STAFF
SURREBUTTAL TESTIMONY & EXHIBIT
OF**

BRIAN HORII

APRIL 4, 2018



DOCKET NO. 2018-2-E

**Annual Review of Base Rates for Fuel Costs for South
Carolina Electric & Gas Company**

SURREBUTTAL TESTIMONY AND EXHIBIT
OF
BRIAN HORII
ON BEHALF OF THE
SOUTH CAROLINA OFFICE OF REGULATORY STAFF
DOCKET NO. 2018-2-E
IN RE: ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS FOR
SOUTH CAROLINA ELECTRIC & GAS COMPANY

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Brian Horii. My business address is 101 Montgomery Street, San Francisco, California 94104. I am a Senior Partner with Energy and Environmental Economics, Inc. (“E3”).

Q. DID YOU FILE DIRECT TESTIMONY AND AN EXHIBIT RELATED TO THIS PROCEEDING?

A. Yes. I filed direct testimony and an exhibit with the Public Service Commission of South Carolina (“Commission”) on March 23, 2018.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. My surrebuttal testimony addresses the rebuttal testimony of South Carolina Electric and Gas Company’s (“SCE&G” or “Company”) witness Lynch regarding SCE&G’s forecast need for winter capacity and a flaw within the regression analysis conducted by SCE&G.

Q. WERE YOU ABLE TO VERIFY THE ANALYSIS CONTAINED IN SCE&G'S REBUTTAL TESTIMONY FILED ON MARCH 29, 2018?

A. No. The analysis contained in witness Lynch's rebuttal testimony required the South Carolina Office of Regulatory Staff ("ORS") to request additional information from SCE&G. On March 30, 2018, ORS issued a Utility Services Request #6 (Surrebuttal Exhibit BKH-1). ORS received the requested information on April 3, 2018, which did not allow me sufficient time to thoroughly review or analyze.

Q. HAS SCE&G PROVIDED EVIDENCE OF THE ZERO POINT FOR SOLAR CAPACITY AS STATED ON PAGE 3 OF WITNESS LYNCH'S REBUTTAL TESTIMONY?

A. No. While witness Lynch cites to the size of the interconnection queue, the size of the queue is irrelevant. Under the Public Utility Regulatory Policies Act of 1978 ("PURPA") methodology, the capacity value is based on the next 100 megawatts ("MW") of capacity incremental to current or already contracted resources. SCE&G further contends that "with 865 MW of solar under contract ... solar has already reached this zero point for capacity." (Lynch Rebuttal, p. 3) However, SCE&G provides no specific evidence to support that contention. Perhaps SCE&G is relying upon its position that solar provides no capacity value because it provides no winter peak reductions. However, as I show throughout my direct and surrebuttal testimony, SCE&G has not adequately proven that point, and therefore has not proven that the capacity zero point has been reached for solar.

Q. SCE&G REJECTS YOUR CLAIM THAT THERE ARE FLAWS AND INCONSISTENCIES IN THEIR 2017 RESERVE MARGIN STUDY. CAN YOU PROVIDE MORE DETAILS TO SUPPORT YOUR CLAIM?

A. Yes. I had difficulty in verifying the results listed by SCE&G in Exhibit JML-2 2017 Reserve Margin Study (“Study”) because SCE&G did not only use the data contained in its Study. SCE&G witness Lynch’s direct testimony Exhibit JML-2 uses regression equations (page 13) to create the graph of winter peak demand response to temperature (page 4) and to calculate the amount of winter peak deviations contained in Table 1 (page 5). I found the regression equations use different temperature variables than those shown in the graph on page 4. It is not possible to recreate the graph on page 4 or Table 1 using the regression equation and data provided by SCE&G in Exhibit JML-2. Moreover, one cannot draw conclusions or insights from the graphs on page 3, because those also fail to match the regression equation that SCE&G presented.

Only through a phone conversation with SCE&G on March 21, 2018, two (2) days prior to the ORS testimony filing date, did I learn of the data inconsistency that gives the false impression of temperature response implied by the regression equations. SCE&G presented regression equations with the variable labeled “hdh” which implies the data is the well understood and commonly used Heating Degree Hour temperature metric. In addition, on page 2 of Exhibit JML-2, SCE&G even states “two regression equations were estimated: one for summer relating daily summer peak demands to cooling degree hours and one for winter relating daily winter peak demands to heating degree hours.”

However, the “hdh” variable used by SCE&G is actually a transformed variable that, while related to hdh is not heating degree hours. SCE&G informed me during the

1 phone conversation on March 21, 2018, the Company subtracted 109.341 from the actual
2 hdh to create the value used in its regression modeling and provided to ORS. Due to this
3 variation in method to calculate hdh, which is not disclosed in witness Lynch's testimony
4 or revealed in the Study, I was unable to accurately evaluate SCE&G's Study results.

5 **Q. DO YOU AGREE WITH SCE&G'S CLAIM ON PAGE 7 OF WITNESS LYNCH'S**
6 **REBUTTAL TESTIMONY THAT COMPARING SUMMER AND WINTER**
7 **GROWTH RATES IS A WAY TO DEMONSTRATE THERE IS NO BIAS**
8 **TOWARDS A LARGER WINTER PEAK FORECAST?**

9 **A.** No. I show on page 19 of my direct testimony, the first year in the SCE&G forecast
10 (2018) is biased to reduce the gap between summer and winter peak demand and thereby
11 make the argument for the need for winter capacity look more compelling. Any growth
12 rates applied to the erroneous first year values would simply continue the bias throughout
13 the forecast.

14 **Q. DO YOU AGREE WITH SCE&G'S ASSERTIONS ON PAGE 9 OF WITNESS**
15 **LYNCH'S REBUTTAL TESTIMONY REGARDING THE HEATING ASPECTS**
16 **OF HEAT PUMPS AND SPACE HEATERS SUCH THAT IT CHANGES YOUR**
17 **VIEW ON THE UPWARD SLOPE OF WINTER PEAK DEMAND?**

18 **A.** No. SCE&G's explanation fits with my statement that there are two (2) types of
19 heating response relationships displayed in the daily winter peak data. On more moderate
20 days, the rise in demand with colder temperatures is moderate because the heat pumps can
21 operate in the efficient range without the need for the supplemental heat strips. During
22 cold temperatures, however, heat strips and other space heaters are used, so the rise in peak
23 demand with colder temperatures is larger. At some point, one would expect even those

1 heat strips and space heaters to begin to reach usage saturation, so further heating load
2 would tail off.

3 This strengthens my argument that all winter days should not be used in the
4 regression modeling. By taking SCE&G's approach, one is forcing a single regression
5 equation to try to fit two different types of temperature response.

6 **Q. DO YOU AGREE WITH SCE&G'S CLAIM ON PAGE 11 OF WITNESS LYNCH'S**
7 **REBUTTAL TESTIMONY THAT, BECAUSE A LINEAR EQUATION SHOULD**
8 **NOT PRODUCE SIGNIFICANTLY DIFFERENT RESULTS THAN THE**
9 **QUADRATIC EQUATION, IT IS SATISFACTORY TO USE SCE&G'S**
10 **QUADRATIC EQUATION?**

11 **A.** No. While the difference in the winter reserve margin due to correcting SCE&G's
12 regression model may appear to be relatively small in isolation, when combined with other
13 corrections to SCE&G's approach, the total impact is a rejection of their position that solar
14 provides no capacity value.

15 **Q. DO YOU AGREE WITH SCE&G'S ASSERTIONS ON PAGES 13-14 OF WITNESS**
16 **LYNCH'S REBUTTAL TESTIMONY THAT YOUR CALCULATION OF**
17 **WINTER DEMAND SIDE RISK IS INCORRECT, AND THAT WITH HIS**
18 **CORRECTIONS, YOUR RESULTS WOULD BE COMPARABLE TO SCE&G'S**
19 **ESTIMATE OF WINTER DEMAND SIDE RISK?**

20 **A.** No. This point highlights the difficulty in addressing SCE&G's substantial change
21 in approach in its resource plan filed in this docket (Exhibit JML-1). SCE&G makes two
22 (2) changes to my estimation of demand side risk. First, they use February as the peak
23 month instead of January. That change does not actually affect my estimate of winter

1 demand side risk, as both my estimate of winter maximum peak and average peak change
2 by the same MW if the peak were to occur in February. Since the demand side risk is the
3 difference between maximum and average peak, increasing both by the same amount
4 results in no change in risk

5 Second, SCE&G calculates the average peak using a mix of months, whereas my
6 method uses the same month for calculating all peak values. Whether this change is
7 appropriate depends upon how SCE&G performs its Integrated Resource Plan (“IRP”)
8 forecasts. In other state jurisdictions, there is a strong direct link between how utility
9 forecasts are prepared in the IRP and how risk is applied on top of that forecast. The basic
10 question is how much risk is recognized in the IRP forecast, and how much additional risk
11 needs to be reflected in the reserve margin. While SCE&G did provide some information
12 on their IRP forecasting process in response to the ORS Utility Service Request #6, it
13 would require more time and additional detailed information in order to determine whether
14 SCE&G’s second adjustment to my demand side risk is correct.

15 If SCE&G’s second change were appropriate, then their change of my demand side
16 risk from 9.1% to 10.2% would be correct. However, that estimate is still 1.5% lower than
17 the 11.7% value from their reserve margin study, and I would consider the 10.2% to be
18 closer, but not comparable, to the SCE&G estimate of winter demand side risk.

19 **Q. IF SCE&G’S ASSERTION IS CORRECT THAT YOUR WINTER DEVIATION**
20 **SHOULD HAVE BEEN HIGHER, WOULD THAT CHANGE YOUR POSITION?**

21 **A.** No. Such a change might change the number of years during which summer would
22 be the binding capacity constraint, but it would not change the fact there will be some
23 number of years over the next fifteen (15) years where summer capacity would be the driver

of capacity need. This debate over regression models and reserve margin methodologies highlights that this is a complex issue that depends upon the relationship between summer and winter capacity needs. This topic area has not received careful scrutiny in South Carolina, nor in North America in general.

Q. DO YOU AGREE WITH SCE&G'S ASSERTION ON PAGE 15 OF WITNESS LYNCH'S REBUTTAL TESTIMONY THAT ITS PEAK DEMAND FORECASTING IS REASONABLE BASED ON A COMPARISON OF HISTORICAL FORECASTS AND ACTUAL PEAKS?

A. No. In fact, the analysis provided by SCE&G in pages 15 and 16 of witness Lynch's rebuttal raises more doubt over the forecasts that SCE&G has used in its 2018 IRP. Over the past four (4) years, SCE&G forecast average winter growth of 36.25 MW per year.¹ The highest growth in any of those years was 106 MW between 2014 and 2015.² Yet for 2018 in the IRP, SCE&G forecasts a gross territorial peak of 5024 MW for winter 2018, which is 388 MW higher than the forecast for winter 2017³ and 256 MW higher than the actual 2017 winter peak.⁴

Q. IS SCE&G'S STATEMENT ON PAGE 19 OF WITNESS LYNCH'S REBUTTAL TESTIMONY THAT "PJM HAS A 16% SUMMER RESERVE MARGIN AND A 27% WINTER RESERVE MARGIN" PERTINANT TO THIS DOCKET?

A. No, and I believe that statement is misleading because it implies that it is appropriate for SCE&G to have a higher winter planning reserve margin than summer

¹ 36.25 MW = (4,636 MW in 2017 minus 4,491 MW in 2013) divided by four years.

² 106 MW = 4,602 MW in 2015 minus 4,496 MW in 2014.

³ 388 MW = 5,024 MW (2018 IRP) minus 4,636 MW (forecast 2017).

⁴ 256 MW = 5,024 MW (2018 IRP) minus 4,768 MW (actual 2017).

1 planning reserve margin because PJM has that as well. PJM does not have a higher
2 planning reserve margin in the winter. SCE&G fails to point out that it is quoting a 16%
3 summer Installed Reserve Margin (“IRM”) and a 27% Winter Weekly Reserve Target
4 (“WWRT”). While they both have “reserve” margin in their description, they are not
5 comparable.

6 The summer IRM is equivalent to the planning reserve margins that we have been
7 debating in this docket. PJM bases its IRM on the common 1 day in 10 years Loss of Load
8 Expectation (“LOLE”) criteria. The IRM is valid for determining amounts of installed
9 capacity that are needed to provide adequate reliability.

10 The WWRT, on the other hand, is not used to determine the amount of capacity
11 that needs to be installed. Rather, it is used as a metric for determining when units can go
12 down for maintenance outages in the winter. The WWRT calculation begins with the
13 resources identified as needed using the summer IRM, and then simulates additional
14 planned maintenance outages of these units in the winter until they increase the annual
15 LOLE risk by one (1) event in one million years. The available reserves from the units that
16 were not put in maintenance outage mode comprise the WWRT. In other words, the
17 WWRT starts with the capacity that is determined to be needed because of the summer
18 capacity need, and then finds how much that capacity can be reduced while still
19 maintaining annual reliability. The 27% WWRT represents less capacity need than the
20 15% summer IRM.

21 PJM is undertaking an evaluation of winter IRM, but I do not believe that study has
22 been completed yet. In the interim, however, it is incorrect to think that the 27% WWRT
23 represents what a winter planning reserve margin would be for PJM.

Q. DO YOU AGREE WITH SCE&G’S CLAIM ON PAGE 22 OF WITNESS LYNCH’S REBUTTAL TESTIMONY THAT THE LOSS OF LOAD EXPECTATION MODEL USED BY THE ELECTRIC RELIABILITY COUNCIL OF TEXAS (“ERCOT”) “DOES NOT ALWAYS GIVE A REASONABLE ANSWER” BECAUSE THE MODEL RESULTS IN A LOWER RESERVE MARGIN?

A. No. SCE&G’s claim is not supported by their own example. The ERCOT example is a case where the balance of the cost of adding new capacity and the estimated value of added reliability to customers justifies a lower reserve margin than that which is estimated using the 1 day in 10-year criteria. The fact that the SERVVM model estimated a lower reserve margin than the 1 day in 10-year criteria does not prove that the SERVVM model or methodology are incorrect.

Q. DO YOU BELIEVE THAT HISTORY JUSTIFIES SCE&G’S USE OF THE “COMPONENT METHOD” FOR THIS DOCKET TO DETERMINE ITS RESERVE MARGIN, AS STATED ON PAGE 8 OF WITNESS LYNCH’S REBUTTAL TESTIMONY?

A. No. The SCE&G method may have been adequate in the past. Indeed, in looking at the reserve margin results from the 2016 IRP, the planning reserve margin from the method produced results that were consistent with the range of reserve margins that I have seen for other utilities and other jurisdictions. However, in this docket, we are reliant upon the reserve margin methodology to determine the difference in reserve margin requirements between the summer and winter season. For this purpose, it is unclear if the component methodology is appropriate. My research indicates that LOLE, Loss of Load Probability (“LOLP”), or related Expected Unserved Energy are commonly accepted

methodologies in the industry. I am not aware of the component method being used elsewhere. I believe that a large change in treatment for valuing PR-2 capacity should not be based on the component method, but should only be considered after the seasonal capacity question is evaluated using industry standard methods.

Q. IS SCE&G'S CLAIM ON PAGE 5 OF WITNESS LYNCH'S REBUTTAL TESTIMONY THAT WINTER CAPACITY NEED IS GREATER THAN SUMMER CAPACITY NEED IN ALL YEARS OF THE PLANNING HORIZON CONSISTENT WITH THE 2018 IRP LOAD AND RESOURCES FORECAST THAT SCE&G PROVIDED AS EXHIBIT JML-1?

A. No. SCE&G's tables on page 5 are not consistent with the IRP forecast and load resource plan supplied by SCE&G as Exhibit JML-1. To check SCE&G's tables, I reconstructed them using the data in Exhibit JML-1, which allowed me to identify SCE&G's error. Shown below are examples of my IRP-based reconstruction calculations for 2019 and 2028.

Table 1: E3 Reconstruction of 2019 Difference in Winter-Summer Need

	2019 Reconstruction	Summer	Winter	Source
1	Peak Demand MW	5111	5071	JML-1, L3
2	Reserve Margin	14%	18%	
3	Total Capacity Need	5827	5984	$(L1*(1+L2))$
4	Less DSM	-275	-223	JML-1, L6
5	Less Solar	-162	0	JML-1, L5 + L7
6	Less Existing Capacity 2018 (S)	-5278	-5278	JML-1, L4
7	Less extra Incremental Winter Capacity (2018)		-186	JML-1, L4 W-S
8	Net Incremental Need	112	297	$(Sum L3:L7)$
9	Difference in Winter-Summer Need		185	$(L8 W-S)$

Table 2: E3 Reconstruction of 2028 Difference in Winter-Summer Need

	2028 Reconstruction	Summer	Winter	Source
1	Peak Demand MW	5750	5473	JML-1, L3
2	Reserve Margin	14%	18%	
3	Total Capacity Need	6555	6458	(L1*(1+L2))
4	Less DSM	-286	-332	JML-1, L6
5	Less Solar	-303	0	JML-1, L5 + L7
6	Less Existing Capacity 2018 (S)	-5278	-5278	JML-1, L4
7	Less extra Incremental Winter Capacity (2018)		-186	JML-1, L4 W-S
8	Net Incremental Need	688	662	(Sum L3:L7)
9	Difference in Winter-Summer Need		-26	(L8 W-S)

My Table 1 results match the SCE&G table shown at the top of page 5 of the rebuttal testimony of SCE&G witness Lynch. Table 2 for 2028 matches the SCE&G summer net incremental need, but the winter net incremental need and the Difference in Winter-Summer Need are 100 MW lower than SCE&G's estimate of 762 MW and 74 MW for 2028. This 100 MW difference exists for all years after 2019, and exists in both the 21% reserve margin and the 18% reserve margin scenarios. This error by SCE&G makes the winter peak look more severe and masks the fact that the summer peak would become dominant in the later years when my 18% winter reserve margin is used.

The errors in the SCE&G tables on page 5 of the rebuttal testimony are due to the Company using estimates of winter Demand Side Management ("DSM") reductions after 2020 that are 100 MW lower than the values presented in SCE&G's 2018 IRP (Exhibit JML-1). SCE&G did not provide a reason for departing from the IRP values, and even if there were a reason, such a change would exacerbate my concerns over assuming zero capacity for PR-2 based on SCE&G's IRP and reserve margin analyses.

My IRP-based reconstructed values for all years are shown in the following tables in Columns A through D. Column E reproduces the difference values from SCE&G's

rebuttal testimony, and Column F shows SCE&G's difference calculation minus my IRP-based results.

Table 3: IRP-Based Reconstruction of Net Incremental Capacity Need and Seasonal Differences (21% Case)

A	Smr: 14.0% Wtr: 21.0%				
	B	C	D	E	F
Year	IRP-based Summer Net Incremental Need	IRP-based Winter Net Incremental Need	IRP-based Net Incremental Need Difference	SCE&G Difference (Lynch rebuttal, p. 5)	SCE&G minus IRP-based
2019	112	449	337	337	0
2020	48	404	355	455	100
2021	131	486	355	455	100
2022	250	536	285	385	100
2023	341	570	229	329	100
2024	409	620	210	310	100
2025	486	677	191	291	100
2026	561	729	168	268	100
2027	627	778	151	251	100
2028	688	826	138	238	100
2029	745	870	125	225	100
2030	797	921	124	224	100
2031	854	971	117	217	100
2032	909	1022	113	213	100

Table 4: IRP-Based Reconstruction of Net Incremental Capacity Need and Seasonal Differences (18% Case)

Smr: 14.0% Wtr: 18.0%					
A	B	C	D	E	F
Year	IRP-based Summer Net Incremental Need	IRP-based Winter Net Incremental Need	IRP-based Net Incremental Need Difference	SCE&G Difference (Lynch rebuttal, p. 5)	SCE&G minus IRP-based
2019	112	297	185	185	0
2020	48	250	202	302	100
2021	131	330	200	300	100
2022	250	379	129	229	100
2023	341	412	71	171	100
2024	409	461	51	151	100
2025	486	516	31	131	100
2026	561	567	6	106	100
2027	627	615	-12	88	100
2028	688	662	-26	74	100
2029	745	705	-41	59	100
2030	797	754	-42	58	100
2031	854	803	-51	49	100
2032	909	853	-56	44	100

Q. LOOKING AT YOUR IRP-BASED RECONSTRUCTIONS, DO YOU AGREE WITH SCE&G THAT WINTER CAPACITY NEED IS GREATER THAN SUMMER NEED IN ALL YEARS OF THE PLANNING HORIZON?

A. No. Column D of Table 4 shows that summer capacity need would exceed winter capacity need in 2027 and all subsequent years. If my corrections for the winter peak demand forecast bias were incorporated (pp. 18-20 of my Direct Testimony, and pp. 14-15 of this Surrebuttal), the result would demonstrate even more years would be designated as summer peaking.

Q. DO YOU AGREE WITH SCE&G'S ASSERTIONS ON PAGE 16 OF WITNESS LYNCH'S REBUTTAL TESTIMONY THAT THE SCE&G PEAK DEMAND

FORECASTS ARE REASONABLE WHEN YOU CONSIDER THAT “SCE&G WOULD EMPLOY ITS DEMAND RESPONSE RESOURCES ON MANY OF THESE HISTORICAL PEAK DAYS”?

A. No. The data that SCE&G used to estimate winter normal peak demand and winter demand side risk in the Study (Exhibit JML-2) was from November 2014 through March 2017. SCE&G did not call for demand response during that same time period, so it would not be possible for an analysis using that data to show reductions from demand response. Since I used a subset of that same dataset to calculate my estimate of normal seasonal loads, it would not be appropriate to compare my normal values that do not reflect demand response to a SCE&G forecast that is reduced by demand response.

Moreover, if one were to compare the SCE&G forecast net of demand response (a firm peak forecast), then the seasonal bias problem is worse than I originally estimated.

Table 5 (below) shows my original estimate of winter bias. Line 5 calculates a substantial difference between the IRP forecast (line 1) and the escalated normal value based on the reserve margin study (line 4). The Table also shows that the seasonal difference is 63 MW larger in the winter, indicating a bias toward overestimating the winter peak and therefore overestimating the need for winter capacity.

Table 5: Winter Peak Bias from Horii Direct Testimony Table 6

		Summer	Winter	Difference
1	Gross Territorial Peak from JML-1 for 2018	5077	5024	
2	Normal 2016 Peak from JML-2, table 1	4744	4630	
3	Assumed growth from 2016 to 2018	2%	2%	
4	Normal 2018 consistent with JML-2, table 1	4839	4723	
5	Difference (L1 - L4)	238	301	63

Table 6 (below) shows the same information, but replaces the Gross Territorial Peak from the IRP with the firm peak demand which is the Gross Territorial peak net of demand response. Line 5 shows that the differences within a season are far less than in my original table (Table 6 of my direct testimony and Table 5 in this surrebuttal), but the difference between seasons is almost double. This indicates that even if considering demand response makes the IRP forecast look more consistent with historical-weather-based peaks, it would not eliminate the issue of winter capacity bias, and in fact would almost double the bias that makes winter capacity appear more needed than summer capacity.

Table 6: Winter Peak Bias using Firm Peaks Net of Demand Response

		Summer	Winter	Difference
1	Firm Peak from Lynch Rebuttal, p. 16	4803	4802	
2	Normal 2016 Peak from JML-2, table 1	4744	4630	
3	Assumed growth from 2016 to 2018	2%	2%	
4	Normal 2018 consistent with JML-2, table 1	4839	4723	
5	Difference (L1 - L4)	-36	79	115

Q. HAVE YOUR RECOMMENDATIONS MADE IN YOUR DIRECT TESTIMONY CHANGED?

A. No. My recommendations remain the same:

- 1) SCE&G's position that avoided capacity cost should be set at \$0.00 should be rejected.
- 2) The PR-2 capacity value be set at 19.5% of the avoided cost per kW from a 100 MW change to SCE&G's base resource plan that excludes any non-committed future resources and reflects any planned plant retirements of firm capacity.
- 3) Require SCE&G to provide an estimate of long-run avoided capacity cost and the calculation for the long-run avoided capacity costs.

- 1 4) In the alternative, require the current capacity value be maintained for both PR-1 and
2 PR-2 until a better capacity value can be provided in the next rate update.

3 **Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

4 **A.**Yes, it does.

Office of Regulatory Staff
Utility Services Request #6
South Carolina Electric & Gas Company
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Surrebuttal Exhibit BKH-1
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Utility Services Request #6



ORS AUDIT REQUEST FORM

DATE: March 30, 2018

TO: Paulette Ledbetter/Byron Hinson

UTILITY: South Carolina Electric & Gas
Docket No. 2018-2-E
SCE&G Fuel Adjustment Clause

FROM: Sarah Johnson

AUDIT PURPOSE: Rebuttal testimony of SCE&G witness Joseph Lynch

REQUEST THE FOLLOWING ITEMS BE PROVIDED BY: Noon on April 2, 2018

Provide the response for the following in electronic format and post to the e-room:

- 1) Provide the workpapers in working Excel format with all formulas intact showing the calculations of the values shown in the table starting on line 8 of page 5.
- 2) On page 8 lines 19 through 21, SCE&G refers to reserve margins calculated using the LOLE methodology in 2013-2017.
 - a. Were LOLE's estimated separately for the summer and winter in any of those studies?
 - b. If so, what are the summer and winter LOLE-based reserve margins from those studies?
- 3) On page 4, SCE&G shows a table of the difference in summer and winter need. The first inputs in the table are summer and winter peak demand that are consistent the IRP table in Exhibit JML-1. Provide workpapers in working Excel format with all formulas intact and explanations of the methods and inputs used to produce the peak demand forecast shown in lines 1 through 3. At a minimum, the response should address the following questions:
 - a. Is the forecast based on a top-down econometric model, or bottoms-up end use models, or some other method?
 - b. How does weather affect the forecast? Are specific weather conditions assumed for each season or end use? (e.g.: 1-in-10 weather, 1-in-2 weather, a specific design temperature) If so, what are the weather assumptions?

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- c. How are load reductions from demand response or curtailable load events treated in the forecast and forecast process? (e.g.: is demand response added back to loads to reconstitute “normal” demand before estimating any econometric models? Are demand response loads somehow added back to the forecast after any econometric forecast is estimated?)
 - d. How do historical peak loads affect the forecast? (e.g.: does the forecast apply a growth rate to some average peak demand?)
 - e. If econometric models are used, what dummy variables are included in the model, and what are the assumed values of those variables for the peak forecast? In particular, if a dummy variable for month of the year is used, what month is assumed for the forecast?
- 4) On page 16, SCE&G discusses the availability of demand response programs that can be employed on peak days. Regarding demand response, provide the following:
- a. A list of all demand response event days, the called amount of load reduction, and the estimated attained amount of reduction for each event. This should be provided going back to Jan 1, 2014.
 - b. An explanation of how demand response has been treated in the 2017 Reserve Margin Study. The discussion should at a minimum address:
 - i. Do the historical loads used to create the regression models reflect loads with or without demand response reductions?
 - 1. If the loads reflect the absence of a demand response program, provide workpapers in working Excel format showing the adjustment from recorded load to reconstituted load without the demand response.
- 5) The IRP table in JML-1 shows forecasted demand response on line 6. Demand response that is achieved during an event is generally less than the amount of subscribed demand response.
- a. Is this demand response in SCE&G’s forecast an expected or subscribed amount?

TO: _____

DATE: _____

THE REQUESTED ANSWERS, RECORD OR DOCUMENTATION:

- 1) ☐ **HAS BEEN PROVIDED TODAY;**
- 2) ☐ **CANNOT BE PROVIDED BY THE REQUESTED DATE, BUT WILL BE MADE AVAILABLE BY _____;**
- 3) ☐ **ITEM(S) _____ IS (ARE) PROPRIETARY AND CONFIDENTIAL BUSINESS INFORMATION;**
- 4) ☐ **THE ITEM WILL NOT BE PROVIDED. (SEE ATTACHED MEMORANDUM).**

SIGNATURE & TITLE OF RESPONDENT